Robert L. Stout, Jr.
Vice President & Head of Regulatory Advocacy & Policy

December 17, 2018

BP America Inc.
1101 New York Avenue, NW
Suite 700
Washington, DC 20005

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Via Federal eRulemaking Portal: http://www.regulations.gov. (DOCKET ID No.: EPA-HQ-OAR-2017-0483)

SUBJECT: BP America Inc. comments on EPA's proposed rule to modify 40 CFR Part 60, Subpart OOOOa regarding methane emissions from new, reconstructed and modified sources in the Oil and Natural Gas Sector (83 Fed. Reg. 52056).

Dear Sir/Madam:

BP America Inc. (BP) appreciates the opportunity to provide written comments to the U.S. Environmental Protection Agency (EPA or the Agency) on the above-referenced proposed rule (the Proposed Rule) on behalf of two of its U.S. oil and gas businesses, BPX Energy Inc. (BPXE, its lower 48 onshore business) and BP Exploration Alaska (BPXA, its Alaska business).

Methane accounts for around 20% of manmade GHG emissions. Since methane is the primary component of natural gas, BP is committed to taking a leading role in addressing the methane challenge. We comment today to highlight the crucial role new technologies will play in addressing the methane challenge and to encourage EPA to create pathways for the prompt introduction of those new technologies.

We believe these technologies not only have the potential to benefit the regulated community but can offer a more efficient and effective way of pinpointing and fixing leaks to achieve the widely shared goal of mitigating the most significant sources of methane emissions.

As detailed below, BP requests that the final rule do the following:

- Allow basin-wide Alternative Means of Emission Limitations (AMELs);
- Streamline the process for approving AMELs;
- Model the approval criteria on Colorado Regulation No. 7; and
- Clarify what constitutes "scheduled" repairs to help address unique Alaska issues

BP's Interest in this Rulemaking

BP has a larger economic footprint in the US than in any other country. We support 125,000+ jobs in the US, and in 2017 alone, BP's operations contributed $85 billion to the American economy.

BPXE is one of the largest producers of natural gas in the United States, operating more than 9,600 producing wells that produce approximately 300,000 barrels of oil equivalent per day. Our operations span 6 states – Colorado, Louisiana, New Mexico, Oklahoma, Texas and Wyoming. Headquartered in Denver, Colorado BPX employs about 1,000 people in five states.

Recently, BP completed the $10.5 billion acquisition of BHP's US unconventional assets. The acquisition adds 190,000 barrels of oil and gas production per day in the Permian and Eagle Ford basins in Texas and in the Haynesville natural gas basin in East Texas and Louisiana. In addition to the oil and gas production by BPXE, BP is the largest marketer of natural gas in North America.

BP has been an Alaska arctic operator for 38 years and currently operates the Prudhoe Bay Unit (PBU), which has produced over 13 billion barrels of oil since 1977. The PBU produces approximately 280,000 barrels of oil per day, accounting for more than half of the state's production. The PBU includes over 1000 wells, 9 processing facilities, and several support facilities. The PBU supports more than 8300 jobs in the state.

BP's Efforts to Mitigate Methane

Recognizing the importance of mitigating methane, we have targeted a methane intensity of 0.2% for our global operations. We also belong to the Oil & Gas Climate Initiative (OGCI) whose companies set a target to reduce their collective average methane intensity of aggregated upstream oil and gas operations to below 0.25% by 2025, with the ambition to achieve 0.20%. OGCI members account for 30% of global oil and gas production. But BP is doing more than setting targets:

- We are testing remote sensing technologies for detecting and measuring methane leaks in our operations. As these technologies are proven and become cost-effective, we will deploy them over time for both new and existing sites. These new technologies are particularly critical in the US where natural gas is produced from wells spread across wide geographical areas.
- We will continue to replace the remaining high bleed pneumatic controllers in our inventory and will replace a number of pneumatic pumps with solar pumps.
- We are reducing venting during liquids unloading by implementing enhanced automation, plunger lift, optimized shut-in cycles, and artificial intelligence.
- We will continue to participate in the Environmental Partnership and share what we learn with its members.

We support cost-effective and efficient methane emission reductions from new, reconstructed, modified and existing sources. Extending regulations to the vastly larger number of existing

sources will depend on cost effective new and emerging technologies, a step which EPA can advance in this rulemaking by easing the way for the introduction of those technologies.

Specific Comments

In its 2016 Rule, the Agency requires oil and gas producers to implement leak detection and repair (LDAR) programs to reduce methane and VOC fugitive emissions at well pads and compressor stations. These programs would entail a periodic survey of all components with the potential for fugitive emissions followed by repair and resurvey of components where leaks are detected. The Proposed Rule would require operators to use optical gas imaging (OGI) or Method 21 to detect leaks.

These LDAR requirements are rigid and are very costly and labor-intensive to implement. Application of conventional LDAR approaches to onshore natural gas production wells is particularly difficult, cumbersome and expensive. Unlike refineries or other plant environments where LDAR requirements have more traditionally been applied, the rule mandates the testing of well components that are widely dispersed and often located at remote sites across thousands of square miles. Costs include the up-front investment in OGI cameras and related equipment but, even more significantly, the training of staff in the proper operation of the equipment and the implementation of the program across the wide span of oil and natural gas production sites. The time and resources required to conduct this monitoring is significant and the training and recordkeeping burdens are substantial, as is the enforcement burden to the Agency.

Basin-wide AMELs

We commend EPA for including a provision in the 2016 rule that allowed alternative monitoring technologies that will achieve at least equivalent emission reductions as the requirements in the rule (known as an "Alternative Means of Emission Limitation" or AMEL). However, the 2016 rule and the Proposed Rule focus too narrowly on requiring the demonstration of equivalency for each site. This limitation seems to arise from practical and legal concerns. We do not think either concern justifies the limitation.

The practical concern is that alternative technologies may need to be adjusted for "site-specific conditions (e.g., gas compositions, allowable emissions or landscape)." (83 Fed Reg. 52080). Even if true, there is no need to bar a multi-site demonstration if adequately addresses these concerns. If a given demonstration fails to address site-specific concerns, EPA can deny the request or impose appropriate conditions on the use of the technology based on its limitations. But there is no reason to automatically rule out such a demonstration and there is nothing in the statute that compels this result.

The legal concern seems to arise from the text of 42 USC 7411(h)(3) which reads in pertinent part:

> "If.... any person establishes to the satisfaction of the Administrator that an alternative means of emission limitation will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the

requirements of paragraph (1), the Administrator shall ***permit the use of such alternative by the source*** for purposes of compliance with this section...." (emphasis added).

EPA apparently reads the phrase "by the source" to disallow the granting of an AMEL that covers multiple sources. That reading is inconsistent with the approach taken throughout the NSPS provisions which focus on developing standards for whole categories of sources. BP endorses the API comments on this point and wants to highlight that a more natural reading of the text would not limit an AMEL to a single source.

The Clean Air Act does not define the term "source." EPA may be reading that term in light of subsequent regulatory definitions that relate to the definition of "source." For example, the NSPS regulations define a "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." 40 CFR 60.2. But Congress did not have future regulatory text in mind when it drafted 42 USC 7411(h)(3). The most natural reading of the term "source" in the 7411(h)(3) context is as a reference to the entity that filed the AMEL request. In other words, the provision reads most naturally as meaning that, if an entity submits an AMEL that is approved, that entity can use the AMEL to meet its compliance obligations.[1] In this reading, the provision says nothing about what can or cannot be included in an AMEL request. If the AMEL is approved for multiple sites, the entity who is granted the AMEL can use the AMEL for compliance for all the sites included in the demonstration.

Placing great weight on the term "source" is not consistent with EPA's past interpretations. For example, in the regulation implementing the AMEL provision of the Clean Air Act, (40 CFR 60.5398a) EPA did not include the "source" term at all. If the word "source" is an important limitation in the statute, it would make sense to have included that key word in the implementing regulation.

Moreover, EPA does not apply the source-specific limitation in the analogous AMEL program for hazardous air pollutants. 42 USC 7412(h)(3) is virtually identical to 42 USC 7411(h)(3) but the 7412(h)(3) implementing regulations explicitly allow an AMEL for categories of sources. 40 CFR 61.12.

In sum, the best reading of 42 USC 7411(h)(3) is that it does not limit AMELs to individual sources. In the worst case, this provision is ambiguous, and EPA has the discretion to interpret it in a commonsense way to give effect to the purpose of the statute and the AMEL provision. The most sensible interpretation is that a demonstration that adequately addresses multiple sources can justify an AMEL that addresses multiple sources.

Streamlined Approval of AMELs

It would be unfortunate if deployment of these new strategies were blocked or inhibited by an overly prescriptive and slow approval process. To avoid this and to create a path toward rapid acceptance of new LDAR strategies, we propose that the rule establish a streamlined, fast-track process for approving new detection technology and monitoring methods that can be easily substituted for the OGI-based survey protocol in EPA's Proposed Rule. Deputy Administrator Darwin has made permit streamlining a priority and has set a target of issuing

[1] In fact, Merriam Webster defines "source" as "one that initiates."

permits within 6 months of receiving a complete permit application. EPA is applying LEAN management principles to identify barriers to prompt action. We suggest that those principles should be applied to alternative technology demonstrations as well.

Where a new technology meets performance specifications outlined by EPA (see the Colorado approach below for a model), the rule should authorize deployment of the technology following a review by the Agency that should not exceed 6 months from submission of a complete data package by the technology developer or an oil or gas company. This firm deadline should be included in the rule itself to assure expedited action so the same or higher methane emissions reductions can be realized while the cost of doing so is reduced. If the agency does not act in 6 months, the demonstration could be deemed disapproved thereby allowing the applicant to file a legal appeal of the final agency action.

As to model criteria for approval, we recommend guidance issued by the Colorado Air Pollution Control Division (CAPCD) under AQCC Regulation No. 7 Regulation 7 is the state's LDAR requirements for methane and other pollutants emitted during oil and gas production. The regulation lays the groundwork for approving alternative technologies by defining "approved instrument monitoring method" (AIMM) as an infra-red camera, EPA Reference Method 21 or "other Division approved instrument-based monitoring device or method." The implementing guidance then outlines minimum criteria for approval of such a device or method, including:

- whether it has "repeatable proven or demonstrated success in the field for hydrocarbon leak detection;"
- "its leak detection capability and reliability;"
- "how leaks and venting events are tracked and recorded;"
- "how effective it is under different types of weather conditions;"
- the ideal and maximum "distance for the lower detection limit;" and
- whether the AIMM is "capable of identifying specific leak/vent locations... or only within a general area."

Under the guidance, the CAPCD will review applications on a quarterly basis and issue an approval letter after the applicant conducts a field test attended by agency staff and the adequacy of the technology has been verified.

Once equipment and methods have been approved for use at oil and gas well sites, all operators should be free to deploy them or to continue to implement the OGI-or Method 21 based approach in the rule.

We would like to discuss with EPA mechanisms through which the final NSPS rule could periodically take account of new LDAR technologies as these become proven and commercially available. We think EPA and the industry should reap any cost-saving and other benefits from the work undertaken by the METEC lab at Colorado State, ARPA-E MONITOR and EDF MDC programs, and from other efforts, as these begin to yield an array of validated and field-tested new sensing technologies and revised monitoring protocols. Reviews of existing technology would help to assess the capabilities and reliability of new sensing devices and related changes in the procedures and schedule for leak identification and repair.

Completion of Delayed OOOOa Repairs

Ambiguity over the treatment of delayed repairs is a particular problem for our Alaska operations. Proposed 40 C.F.R. § 60.5397a (h)(3) provides as follows:

> If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a scheduled vent blowdown or within 2 years, whichever is earlier. (emphasis added)

There is no regulatory definition of the terms "scheduled," "well shutdown," or "well shut-in." Oil and gas production in the Prudhoe Bay Unit (PBU) is an extremely dynamic process, as explained below. Based on the lack of regulatory definitions for key terms, it is uncertain whether the well repair work requirement is triggered when wells are briefly taken off production (or "offline"), which frequently occurs in PBU with very little advance-notice regarding the specific wells that will be affected.

The PBU has 1032 operable wells with production flowing into 7 different processing centers. Generally, 600 to 700 wells will be online at any given time. Under normal operations in PBU, the specific wells being used to produce oil and gas changes constantly. Online and offline wells are reviewed every day, sometimes multiple times throughout the day, and adjusted to match current field conditions. Primarily, wells are placed online or taken offline to provide proper gas rates to match the facility handling constraints based on three factors:

- ambient temperature shifts;
- maintenance events on interlinked facilities; and
- planned events (e.g., pigging operations) that require briefly taking wells on and offline – where those wells cannot be pre-identified, usually until the day of operations.

Due to the interlinking of the facilities and the current gas handling constraints, any of the above three factors may require taking multiple wells offline sometimes with less than a day's notice. For the safe, reliable, and efficient operation of PBU, we must constantly cycle wells to provide constant, steady-state flow to the processing centers to avoid plant upsets and flaring events. However, when well repairs are necessary, we also must safely and efficiently complete the work, which requires planning. Given the dynamic way that PBU is operated, there is often little advance notice that a particular well will be taken offline, which makes safely planning the work in advance extremely challenging.

Regarding ambient temperature shifts, the gas handling capacity of the compressors decreases as the temperature rises. As this occurs, we must throttle back the amount of gas sent to the processing facilities to keep them from flaring. To efficiently do so, we take wells offline and bring them back online to reach the proper gas-to-oil ratio (GOR) within the gas handling limits of our facilities. It is impossible to plan the selection of these wells in advance, as the daily set of wells online changes based on dynamic field conditions, the other two factors above, and the fact that the rate of the temperature change is not constant.

The second factor is that PBU's process is interlinked across facilities. Because of this linkage, BPXA must optimize operations across the field to maintain safe, reliable and efficient production. If a facility has a planned or unplanned event, the production team must look to other assets to take wells on or offline based on the amount of gas the other facility was providing through the formation. Again, the selection of the wells during such events will be based on the current overall field and facility conditions, GOR, and the ambient temperature.

The third factor concerns planned events that require taking wells offline, but where we have little advance-notice regarding which specific wells will be impacted. For example, pushing a pipeline pig from a well site to a processing facility requires a specific velocity to safely execute the task. Based on current gas rates, specific wells must be taken offline or brought back on to maintain that velocity. Again, based on current GOR, overall field performance, and ambient temperature, we make that determination the day of the pig run.

BPXA requests that EPA guidance confirm that taking wells offline in response to the above factors is not a "scheduled" shut-down or shut-in for purposes of triggering a well repair required under 40 C.F.R. § 60.5397a(h)(2). For clarity, it would be useful to have a minimum advance notice to qualify as a "scheduled" activity. We recommend that any shut down or shut in that occurs with less than 30 days advance notice would not quality as a "scheduled" event and would not require a repair during that event. With less than 30 days' notice, we are concerned that repair operations cannot be undertaken safely. Such guidance would provide regulatory certainty as well as help BPXA to safely, reliably, and efficiently operate. This would mean not only safely maximizing production, but also reducing the likelihood of plant upsets and decreasing emissions from flaring.

<u>Conclusion</u>

BP appreciates EPA's efforts to solicit stakeholder input to this rulemaking. Should you have any questions, please contact me at (202) 346-8566, or via e- mail at robert.stout@bp.com or Jim Nolan at (202) 457-6592 or via e-mail at james.nolan@bp.com.

Thank you for considering these comments.

Respectfully submitted,

Robert L Stout Jr / Jam

Robert L. Stout, Jr.
Vice President and Head of Regulatory Affairs
BP America Inc.